INCENTIVES FOR TRANSMISSION ENHANCEMENT

A Position Paper of the
Electric System Reliability Task Force
Secretary of Energy Advisory Board
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1. INTRODUCTION

The U.S. electric industry is characterized by many vertically-integrated utilities, each of whose generation and transmission systems were planned and for the most part are operated as an integrated whole. Restructuring of the electric-power industry and unbundling of transmission from generation create challenges for reliably operating the existing transmission system and raise concerns about the future adequacy of transmission planning and incentives for investment in transmission enhancements.[1] In the future, decisions regarding whether to build transmission or generation or both, or to dispatch customer load reductions will be made by multiple market participants, with decisions about one approach or another being informed by but not necessarily integrated with decisions about other approaches.

Traditionally, transmission has been viewed as a monopoly function, with utility investments recovered through regulated rates. If, however as some believe, grid construction and maintenance lack compelling natural monopoly characteristics, regulated systems of cost recovery may not long endure at state or other levels. Even acknowledging this viewpoint, the Task Force nonetheless believes that this sector's monopoly aspects remain robust enough to justify improving rather than dismantling price regulation. And we are concerned that state and federal-level regulation is not doing enough to promote and shape sound investments in grid reliability.

This paper discusses these issues of ensuring adequate incentives for transmission enhancement, starting with a brief background on the historical industry structure to place these concerns in context. The nature of operational reliability and transmission congestion (typically the driving force for transmission enhancement), and physical interactions among generation, transmission, and demand-side alternatives, are also examined. The paper also discusses alternative industry structures and the issues they raise with respect to incentives for adequate transmission enhancements. Finally, the paper suggests Task Force recommendations on Federal Energy Regulatory Commission (FERC) rules, market structures and future research. These recommendations relate to adequate incentives for efficient transmission enhancements and

1 Transmission "enhancements" can include construction of new transmission lines, substations, and facilities; upgrading existing lines and facilities; deployment of new technologies such as FACTs devices and distributed generation; or the implementation of advanced controls that increase the capacity of the existing system; and for the purposes of this discussion, demand-side alternatives that relieve congestion.

dovetail with other recommendations adopted by the Task Force on Electric System Reliability.[2]

2. HISTORICAL INDUSTRY STRUCTURE

Historically, vertically-integrated electric utilities designed and operated integrated transmission and generation systems. The primary historical transmission function was to connect the utility's generators to the utility's customers and to operate the system reliably. Utilities interconnected their transmission systems with other utilities' systems to increase reliability and share reserves, as well as take advantage of economic exchanges. When transmission congestion required generation to be re-dispatched to support reliability or economic transactions, the utility was able to evaluate generation and transmission implications (and even occasionally load-reduction options) in both a real-time basis and for long-term planning purposes, if needed. A solution for new transmission facilities, based upon current conditions as well as expectations for load growth and future electricity prices and availability, could be developed and presented to the regulator for approval, subject to a number of constraints relating to siting and cost issues. The selected strategy could then be implemented and the costs passed on to customers. Investment decisions were made by utilities and regulators with prudent investment and operational costs borne by customers.

3. CONGESTION RELIEF: PHYSICAL ALTERNATIVES AND INTERACTIONS

In the absence of congestion (current or anticipated) and short of operational reliability problems, there is no need to invest in transmission expansion; the existing system is adequate to handle all desired transactions on a reliable basis. In theory, such a system can allow for a minimum-cost dispatch of generation (and load reductions). Congestion results when there is a desire (for either reliability or commercial reasons) to move more power through a transmission line (or set of transmission lines or an interface) than the transmission line (or interface) can accommodate.

Figure 1 presents an example where the flow from Area A to Area B can become congested.[3] A consequence of a congested interface is that it creates a bottleneck which prohibits delivery of otherwise economic energy supplies to consumers on the high-cost side of the bottleneck. This

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[2] The following reports have been approved by the Secretary of Energy Advisory Board, Task Force on Electric System Reliability:
- July 1997, *Interim Report*,
- November 1997, *Maintaining Bulk-Power Reliability Through Use of A Self Regulating Organization*,
- March 1998, *The Characteristics of the Independent System Operator*,
- May 1998, *Technical Issues in Transmission System Reliability*,
- May 1998, *Ancillary Services and Bulk-Power Reliability.*

[3] Figures 1 and 2 are simplifications for illustrative purposes. In reality, transmission interfaces are generally crossed by multiple transmission lines.

means that these consumers pay more for their power than they would if there was sufficient transmission capacity to carry all economic transactions. In other words, energy costs are genuinely location dependent, given transmission constraints. When the load in Area B reaches a level where the transmission interface is fully loaded (800 MW in this example) and no more power can be delivered from Area A to meet demand in Area B, then more expensive generation than would otherwise be required (G1 at $28/MWh, or $6/MWh above the Area A cost) must be run in Area B. Although congestion is based upon reliability requirements, the consequences are economic.

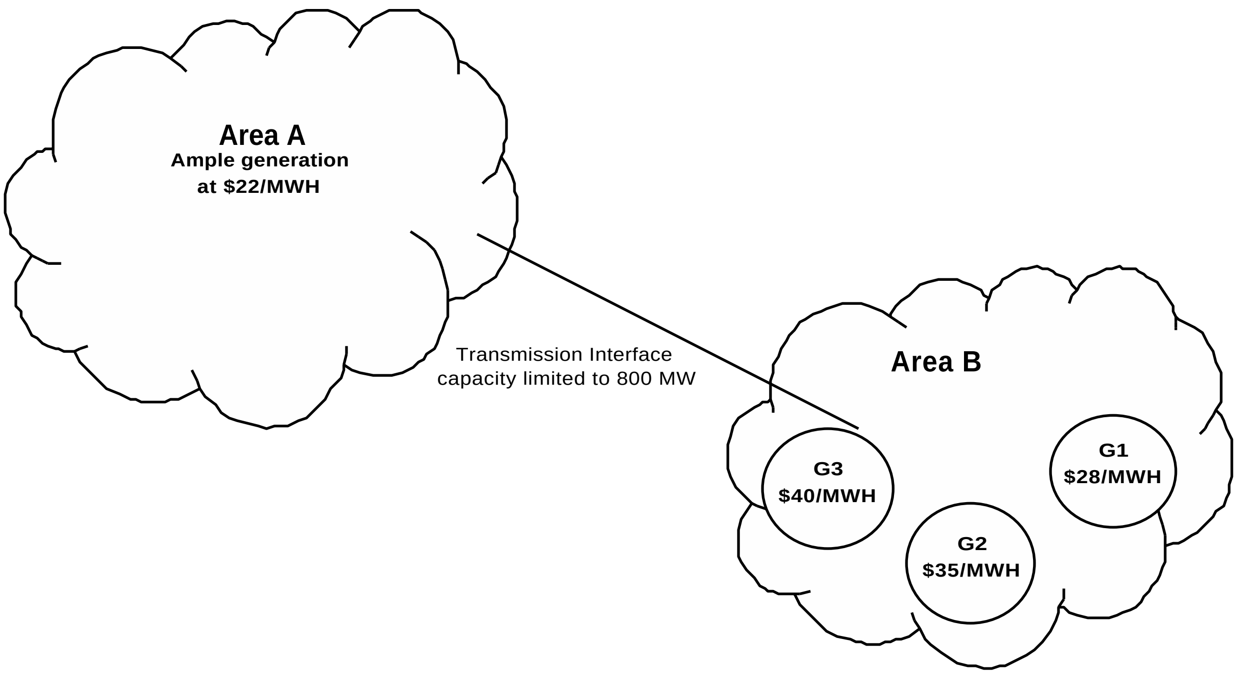

Figure 1 Congested transmission interface that limits power flows from Area A to Area B

Presuming that congestion results in economic inefficiencies, the option to relieve congestion through transmission enhancements is desirable where cost-effective. In any particular circumstance, there are usually several alternatives to relieve congestion and the goal should be to devise systems of incentives that produce cost-effective means to reduce such congestion where it is economical to do so. Effective relief methods can include installation and/or operation of large or small scale generation in the congested area for energy production, for voltage support, to enhance stability, or to reduce flows on specific lines. Transmission-based solutions can include construction of new lines or facilities, upgrading of lines or facilities, installation of voltage

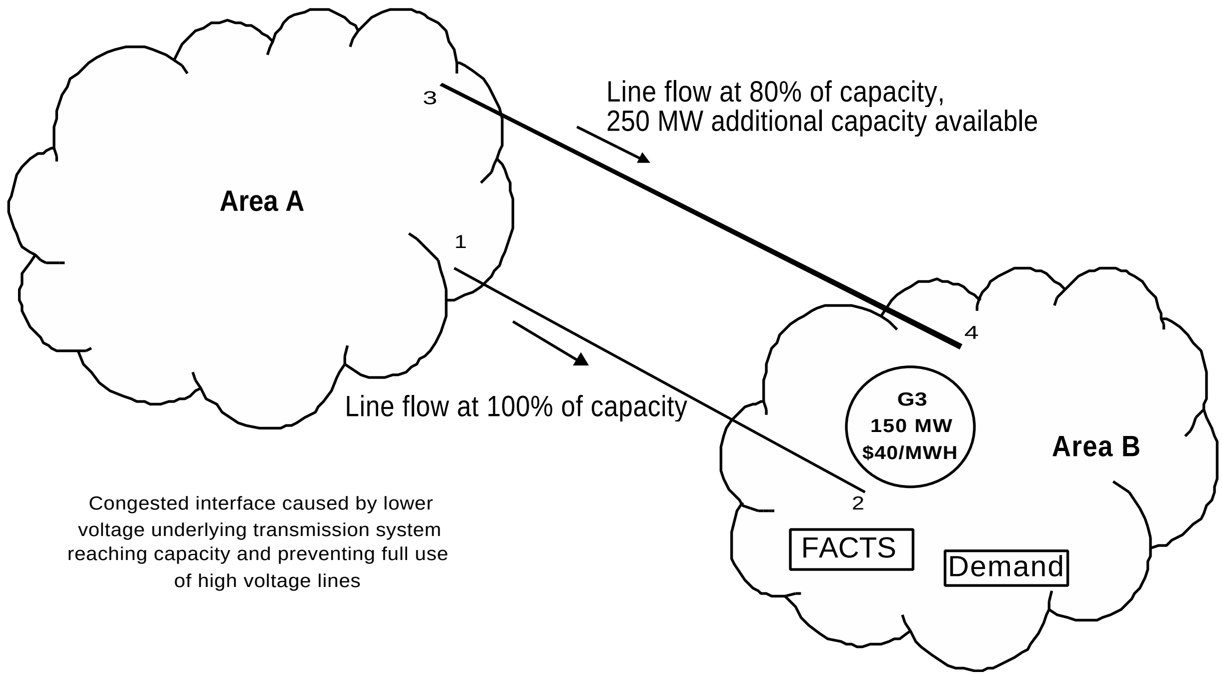

Figure 2 Alternatives to limit flows on line 1-2 and allow use of additional capacity on line 3-4

support (capacitors, inductors, voltage regulating transformers, static condensers, or static var compensators), or installation of flow-control devices (phase angle regulators or FACTs devices), and power system stabilizers at generating stations. The technologies allow more power to be delivered over a line or to operate the system more reliably. Load management approaches (including bidding interruptible load in response to different market clearing prices) can also provide congestion relief under certain circumstances. The incentives (and moreover, disincentives) for a particular type of relief depend on various economic, technical, informational, and regulatory elements.

By way of example, Figure 2 shows a situation where one of two parallel paths is loaded to capacity before the other, leaving 250 MW of transmission capacity unavailable to support power transfers. Accepting the transmission limit and allowing the more expensive generation market in Area B to operate may be the best solution if the congestion is infrequent, does not last long, or the price differential between areas A and B is not great. Alternatively, a FACTs device or phase-angle regulator could be used to block the flow on the limiting line, allowing additional power to flow on the line with remaining capacity. Running a specific unit (generator G3 in this case, located at the delivery end of the congested line) out-of-economic-merit order may reduce flows on the limiting line sufficiently to allow additional energy to be imported over the parallel path. Similarly, controlling demand, either throughout Area B or specifically near the termination of the limiting line, can relieve congestion. In all cases, a transmission enhancement is required to reduce the cost of service in Area B.

4. ISOs AND CONGESTION RELIEF

Independent system operators (ISOs)[4] have been proposed as a way to facilitate competitive generation markets in an environment where some power-system facilities and functions remain inherently monopolistic. This Task Force has recommended that ISOs have broad geographic coverage. Where ISOs have been established as the means to assure non-discriminatory access to transmission for all generators in a region's wholesale (and retail) power markets, functions that require allocation of existing scarce monopoly resources, such as existing transmission capacity, among competing parties in an agreed manner should be under the control of the ISO. Rules governing the desired level of reliability can be established as can rules governing the relative priorities of individual transactions in use of the transmission system. With rules in place an ISO can then determine how best to operate the transmission system to reliably accommodate as many users as possible on a non-discriminatory basis, and allow competitive markets to function. Market rules can be designed that solicit and select among generation redispatch, demand-side solutions, or transaction curtailment as ways of dealing with specific congestion, both on a long-term planning basis and in real-time operational markets.

Two fundamental problems arise, however, when trying to decide whether it is desirable to make capital investments of one sort or another to alleviate congestion. The first problem is that there is no agreement on the appropriate way to price use of transmission from the point of view of creating efficient price signals for investment (supply) or use (demand). PJM is using location-based marginal energy prices and firm transmission rights as the means for indicating the need for and cost-effectiveness of investments in transmission enhancements. In other regions such as New England, market participants have adopted a region-wide postage stamp pricing system for transmission, with cost allocation for new transmission enhancements still in discussion. There is no national consensus on the correct approach, or on which approach creates the proper incentives for investment. However, with a variety of pricing approaches in place across the country, actual experience will help increase our understanding of the advantages and disadvantages of the different approaches to transmission pricing.

The second problem is that competing options for relieving congestion operate in different markets with different structures: generation and demand-side solutions operate primarily in competitive markets, while transmission remains largely a regulated monopoly service. When a single investment (a generator, for example, or a special technology[5] added on to transmission facilities which enhances the capabilities of generation resources) is selling into both a competitive and a regulated market, it is difficult to unambiguously determine the appropriate allocation of costs between those markets and to establish appropriate incentives for efficient investments (or product substitution) in those markets. Uncertainty may lead to under investment or cross-subsidization.

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4 The ISO could be a Transco or other type of system operator so long as it does not have a financial interest in energy markets.

5 Special technologies might include fixed capacitors, inductors, or power electronic controllers.

The lack of an accepted method for individual transmission facilities to competitively price their use makes it unclear that the same market forces that are expected to work well for generation investment can be harnessed for transmission. With generation, an investor can evaluate a potential market, develop a project proposal at a particular location, determine expected costs and profits, and then decide if it wants to risk its capital. After the facility is placed in operation, its use and profitability depend on how the owner operates its facility and prices the production and how the market responds to these and other price offers. Transmission is inherently different. The extent to which a transmission element is used in real-time depends on the electrical impedances and the overall system flows, not the price charged for the service. With very few exceptions, customers can not choose the path on which power will flow based upon offered price.

For the time-being (at least) and for the long-term (at most), responsibility for grid construction, operation, and maintenance is expected to be a monopoly with its use and cost overseen by government regulators and operated in many parts of the country by independent system operators. Although ISOs are expected to be adopted, their exact scope is not known and will probably vary from region to region. ISOs should conduct planning and implementation for transmission enhancement, much as vertically integrated utilities do today and provide congestion-based signals so that markets might resolve congestion-related problems through market forces.

An ISO would identify constraints where congestion was likely to impact reliability. It could then do a variety of actions. It might ask the local transmission company to build transmission, or it might request proposals to construct and/or own the needed facility. Other ownership structures and other physical solutions (non-transmission) may be proposed for the ISO to evaluate. It might share pricing and other planning information with other market participants. The ISO might request proposals for solutions. Proposals could be generation, transmission or load based. The ISO could select the least-cost solution for the overall system and would support approval from the appropriate regulatory authority for investments made by others (e.g., generation developers or transmission owners), the requestor of firm transmission service that caused the need for new transmission enhancements, or the ISO[6] itself. The solution could be implemented and the costs could be included in overall transmission rates.

An ISO would also provide congestion-related pricing signals to transmission users when allocating access across constrained interfaces and through settlements on contracts following implementation of measures to relieve reliability constraints. Transmission capacity constraints would be based upon reliability criteria and transmission loading.[7] Market participants themselves could decide whether and when to propose transmission investments. In the absence of investment, any resource which is fully interconnected with firm transmission rights would enjoy priority service during periods of congestion.

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[6] The independence of the ISO from any of the entities proposing solutions will significantly increase the confidence that all proposals are being evaluated equally.

[7] Transmission constraints would be met in real time by transaction curtailment if there were not sufficient time for market response.

In recent decades, it has become extremely difficult to site and build new transmission lines, especially above ground lines on new rights of way. Regulatory requirements include environmental impact assessments, proof of need and proof that such transmission investments are the least-cost alternative. These issues of need, cost, and benefit are complicated when transmission operates in interstate commerce with the distribution of benefits and costs imperfectly aligned with state boundaries.

Furthermore, there are significant timing issues regarding the lead times for new generation investments made in response to market price signals - which might take 10 - 48 months, depending upon the type of generation investment - and the lead times for transmission enhancements - which may take as little as a year or two for certain technical solutions or as long as 5 - 10 years for construction of major new transmission lines. In a generation market with increasing energy prices, there could be a demand for new generation, but the timing misalignment between transmission planning and investment (including permitting) and generation siting and investment could create a significant barrier to entry for new generation. A reactive approach to transmission planning, in which transmission analyses are carried out in response to generator requests for firm transmission, will exacerbate this problem.

5. TASK FORCE FINDINGS AND RECOMMENDATIONS

Investors, under any structure adopted, will require clear and stable rules to encourage them to risk their capital. As well as being clear, the economic signals need to be adequate to induce appropriate investments.

- At present there is no national consensus on the appropriate way to price transmission services in order to provide optimal incentives for both investment in transmission facilities and the demand for transmission services. Given the lack of consensus, it is appropriate and desirable that a variety of approaches are being tested around the country. The FERC should monitor progress with these different pricing approaches so that we can learn more about the advantages and limitations of the alternative methods.

- Energy generation will be increasingly market based. Generation investment decisions will be made by commercial entities assuming the risks associated with their decisions. But the viability of a generator depends in part on the market it is selling into. If that market is influenced by congestion the investor will want information concerning how long that congestion is likely to last. Similarly, decisions concerning congestion relief investments should be influenced by expectations concerning future generator locations. Methods for sharing generation and transmission planning information, without passing commercially sensitive information between competitors, should be developed.

- The FERC should approve tariffs designed to compensate those entities making cost- effective investments to relieve congestion. While allowing for variation across regions, the FERC should explain the range of transmission compensation structures it will allow, and the extent to which generation investments that perform transmission functions are subject to rate regulation as transmission or conversely the extent to which transmission investment that adds to generation capacity in the region qualifies for unregulated market prices and rates of return.

- Without a robust open market addressing grid congestion, many believe there is minimal incentive for commercial entities to conduct or pay for long-term transmission research. Long-term research to advance transmission technology would then be in the public interest and should be open rather than proprietary. Broad-based mechanisms to support basic and applied technology research should be encouraged, including tax credits for long-term research with broad public benefits.

- Monitoring outcomes of changes in the wholesale electricity market is important to determining the effectiveness of the system operator and its rules. Just as the North American Electric Reliability Council makes assessments today of regional reliability and identifies sensitive situations, the national reliability organization should assess interfaces which are constrained presently and review these assessments periodically. The system operator can use this information to moderate its rules and pricing to cost- effectively reduce constraints.